COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Edison Company	)	
Cambridge Electric Light Company	)	**D.T.E. 03-121**
Commonwealth Electric Company	)	
d/b/a NSTAR Electric	)	

Direct Testimony

Andrew G. Greene

On behalf of

The Solar Energy Business Association of New England

March 16, 2004

DIRECT TESTIMONY OF ANDREW G. GREENE

I. Introduction

Q. Please state your name and business address.

A. My name is Andrew G. Greene. My business address is 77 South Bedford Street, Burlington, MA 01803.

Q. By whom are you employed and in what capacity?

A. I am employed by Navigant Consulting, Inc. ("NCI") as a Principal within the Energy Resources and Operations group of the company's Energy Practice.

Q. Please describe your current duties and responsibilities.

A. I am responsible for providing consulting services in the areas of energy and environmental policy, rate design, regulatory compliance, strategy, and project development. I work with a wide variety of clients, both public and private, in most facets of the energy industry.

Q. Please summarize your educational and professional background.

A. I received my Bachelor of Arts in Economics from Tufts University in 1983, and a Masters in Business Administration from Boston College in 1990. My work in the energy and environmental field began in 1985 when I joined the Massachusetts Department of Public Utilities as an Economist in the Gas and Water Division. I was later promoted to Assistant Director and then Director, and had primary technical responsibility for supervising gas and water utility cases and other matters pending before the Department. In 1991, I was appointed Assistant Secretary for Policy and Planning at the Massachusetts Executive Office of Environmental Affairs. In this position, I coordinated legislative and regulatory policy matters involving EOEA and its five line agencies. In 1995, I began my present work as and energy and environmental consultant, subsequently joining Navigant Consulting, Inc. in 1999, where I continue in this capacity. My resume is attached for additional information.

Q. Have you previously testified in front of the Department or other regulatory agencies?

A. Yes. I have presented testimony in several proceedings before the Department of Public Utilities including: D.P.U. 92-230 and D.P.U. 94-162, as well as before other state utility regulatory bodies in Rhode Island and Vermont. I have also testified before various state legislative committees on environmental- and energy-related matters.

Q. What is the purpose of your testimony?

A. I am testifying on behalf of the Solar Energy Business Association of New England ("SEBANE") with regard to the standby tariffs proposed by NSTAR for its Boston Edison, Cambridge Electric, and Commonwealth Electric service areas. In particular, my testimony analyzes the rate design methods used by NSTAR ("Company"), and the practical and policy considerations relevant to onsite photovoltaic ("PV") generation and, more broadly, distributed generation ("DG"), which would be affected by such rates. My testimony evaluates the specific impacts of the proposed standby tariffs on two illustrative New England end-use facilities: a large grocery store (with a high load factor typical of this class), and a large office building (with a low load-factor typical of this class). For each end-user, I have evaluated the effect of the applicable standby rates in each service area, coupled with one of the following distributed generation technologies: a 200 kW flat-roof PV array (operating at 16.4% capacity factor);

and a 200 kW fossil GenSet that operates at 100% capacity factor. The results of this analysis provide some clear insights about the effect of the Company's proposed standby rates. SEBANE as well as Fuel Cell Energy, Inc sponsor the proposed language offered later in my testimony on "elective exemptions" to the standby rate under specified conditions.

Q. Please summarize your findings.

A. The Company's standby rate proposal raises serious concerns and should not be accepted by the Department for the following reasons: (1) The proposal is a solution to a problem that is feared, but not yet material according to annual DG market data compiled by the Department and submitted to the Legislature; (2) The Proposal does not provide a proper context to evaluate the important costs and benefits of DG including: its role in distribution system planning and possible Transmission and Distribution (T&D) cost deferral; grid reliability and security; Renewable Portfolio Standards (RPS) compliance; Clean Air Act compliance; attainment of regional climate change policy goals; and economic development opportunities; (3) The standby rate incorporates a fundamental re-design of several existing general service rate classes – but only for standby customers. This creates rate equity issues regarding similarly situated customers in the same rate classes; (4) While the rate impacts from the standby rates are mixed, the negative impacts seem to outweigh the benefits, and could injure nascent DG market development.

If the Department chooses instead to adopt some form of standby rate in this proceeding, I recommend that DG customers be granted "elective exemption" from the standby tariff provided certain specified conditions are met, as described later in my testimony.

Q. Is there a "DG problem" that exists today and necessitates the use of a standby charge to prevent embedded cost shifting to non-DG customers?

A. No. Although distributed generation accounted for only 0.538% of the total megawatt-hours distributed by utility companies in Massachusetts in 2002[1], the Company is concerned that DG could result in unrecovered embedded costs that would be shifted to other customers. This scenario underlies the Company's standby proposal, even though the D.T.E. report on Self-Generation shows that DG in Massachusetts is barely a blip on the radar screen.

M.G.L. Chap 164 Section 1G (4)(g) offers some useful guidance in determining when DG has reached the point where ratemaking remedies are warranted. This provision specifies that a utility shall not impose an "exit charge" for on-site generators if the total revenue impact of such customers is less than or equal to 10 percent of the annual gross revenues collected by the service provider. The statute allows the Department to make a determination that, if a "significant adverse impact" results from on-site generation below the 10% threshold "during the remaining period of transition cost recovery" the Department may order that an exit fee be paid. To date, no such fees have been levied and the 10% threshold is far from being reached.

Q. In what context should the Department review the standby rate proposal?

The Company's standby rate filing reflects familiar embedded cost ratemaking

[1] D.T.E. 2002 Annual Report Concerning Self Generation, p. 3 Data for 2003 is not yet available.

principles, presented as if this case were a routine rate design proceeding. In fact, the Company's filing is likely to be the most determinative policy decision facing the Department about the role DG will play in the energy future of the Commonwealth. Many believe that clean, efficient, renewable, and modular DG technologies can yield significant financial and environmental benefits -- for DG owners and non-owners alike. Standby rates are a serious threat facing the nascent DG market. The Department should review the standby rate issue in the context of the full costs and benefits of DG technologies and their potential role as a system resource, rather than as an isolated rate matter.

Q. Please describe the key features of the Company's proposed Standby tariffs.

A. The Company's proposal has two key elements: (1) a re-design of four general service rates to assign additional distribution-related costs to the demand charge portion of the rates to better facilitate a standby charge; and (2) the development of the standby charge by unbundling its existing general service rates into the following components:

- standby delivery service;
- supplemental delivery service;
- supplier service; and
- rate adjustments (such as energy efficiency charge, renewable energy charges, and other miscellaneous charges).

The main objective of the Company's proposed standby rates is to prevent customers who install onsite DG equipment (over 60 kW) from avoiding distribution-related charges that would have been collected in the absence of the customer's DG system. The standby rate accomplishes this objective by requiring DG customers to pay a standby charge equal to the maximum output rating of its DG equipment (in kW) times a distribution-related demand charge.

The supplemental delivery service portion of the standby rate includes all rate components of the original general service rate (modified to move distribution-related demand costs out of the energy charge and into the distribution demand charge) except the customer charge, which is collected via the standby delivery service portion of the rate. Demand meters are used to record the maximum fifteen-minute demand during the monthly period, and energy meters record kWh consumption for all variable rate components such as supplier services (e.g. standard offer or default services), energy efficiency charges, renewable energy charges, etc.

To prevent the customer from paying twice for capacity already reserved under the standby delivery service, the Company will reduce the metered demand by the difference between the maximum output rating of the DG equipment (called "Contract Demand") and the actual output of the DG units "for the period of the reduction or outage." Witness Lamontagne's testimony (Exhibit NSTAR-HCL-5) indicates that the reduction in DG output relative to contract demand is measured during the same period in which the demand meter records the customer's non-coincident peak level.[2]

[2] Although Mr. Lamantagne provides a clear example of how a credit relative to contract demand would work, he asserts that the proposed rate "does not describe a situation that might lead to a reduction of the contract demand." [Response to DTE 1-2]. He suggests language that would reduce the contract demand to the lower of: (1) the maximum output of the customer's generation in the current billing month and the prior eleven billing months; or (2) the actual maximum standby established by the customer in the current

Q. Why did NSTAR propose modifying the rate designs for SB-1 for Commonwealth and the General Service Rates SB-2 for Boston, Cambridge, and Commonwealth?

A. The purpose of a standby charge is to recover fixed costs incurred to serve customers, whether or not they use the service. For customers with DG equipment, the Company asserts that such costs are, in fact, incurred, but that normal rate mechanisms are not sufficient to ensure proper recovery. This is because DG output can partially, or completely obscure the potential demand such customers place on the system if their equipment has an outage. The more frequently the DG equipment operates, the more likely that it will lead to reduced demand charges.

A standby charge is intended to recover all fixed (demand) costs related to a utility plant that is essentially dedicated to serving a given customer. Although Department rate designs attempt to assign demand-related costs to the demand portion of the rates and variable costs to the energy portion of the rate, this is not always possible given other rate objectives such as rate continuity and fairness. For whatever historical reason, four of the Company's general service rates retain some distribution-related costs on the energy portion of the rate. Therefore, for the Company to devise a standby charge that recovers all of its distribution-related costs these costs must be reassigned to the demand-portion of the rate.

Regardless of the cost causation logic, reassigning distribution-related costs from

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and prior eleven months. This approach is inconsistent with the example offered in Exhs. NSTAR-HCL-5 and NSTAR-HCL-1, p. 28 lines 14 – 23 which depict the contract demand credit being measured as the shortfall of the DG output relative to contract <u>demand in the specific hour in which the monthly demand level is established</u>. The language suggested by Mr. Lamantagne in response to DTE 1-2 appears to unfairly inflate the revenues the Company would otherwise collect under the supplemental delivery service the current per-kWh charge to a higher distribution demand charge will have three inevitable effects. First, those customers who have a higher load-factor than the class average will benefit when costs are shifted from energy to demand components. Second, these changes redistribute intra-class revenue requirements and may increase or decrease intra-class cross-subsidization. For the time being, other members of the affected rate classes (who are not DG customers) are spared the rate redesign process. Third, if the standby rate is adopted, there will undoubtedly be additional pressure in the next NSTAR rate proceeding to introduce similar rate design changes to customers who are not directly affected in this case.

Q. What are your observations concerning the impact of the proposed standby rates on DG customers?

A. To address the potential rate implications for DG customers, I have developed an extensive spreadsheet model that tests the operation of the standby rates over a range of customer load shapes, DG technologies, and NSTAR rate classes to yield a reasonable overall understanding of how these rates operate.

First, I selected two representative end-use customers assumed to have the capability and potential interest to install onsite DG equipment. Using load shapes available from ITRON, Inc.[3], I developed a load profile over 8,760 hours in a normal year for two customer types (see Figures 1-4):

- A large New England grocery store (approximately 100,000 sq. ft) that uses gas for space heating. Due to the relatively constant use of refrigeration, freezers and other systems, this customer has a fairly high load factor of

[3] Load Shapes were obtained at http://capabilities.itron.com/eShapes/

63.7%; a peak load of 855 kW, and annual energy consumption of 4,773,660 kWh.

- A large office building in New England (approximately 318,000 sq. ft.) that also uses gas for space heating. The customer's peak load is 1,473 kW; the annual consumption is 4,773,660 kWh; and the load factor is 37%. The low load factor of this customer is fairly typical given the limited usage of the building on nights, weekends and holidays.

Figure 1: Peak Load Day for Large Grocery (as measured by meter) with PV – January

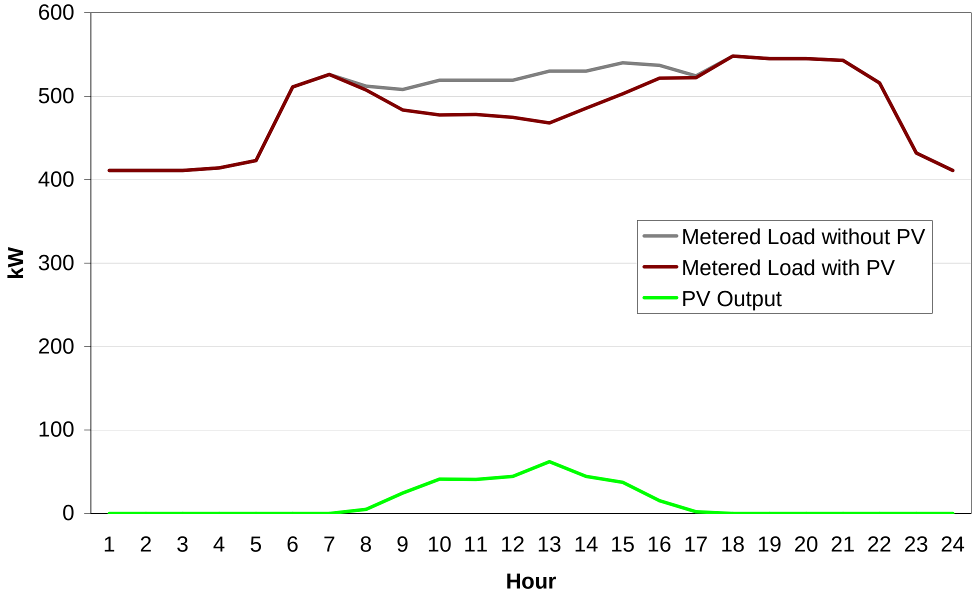


Figure 2: Peak Load Day for Large Grocery (as measured by meter) with PV - April

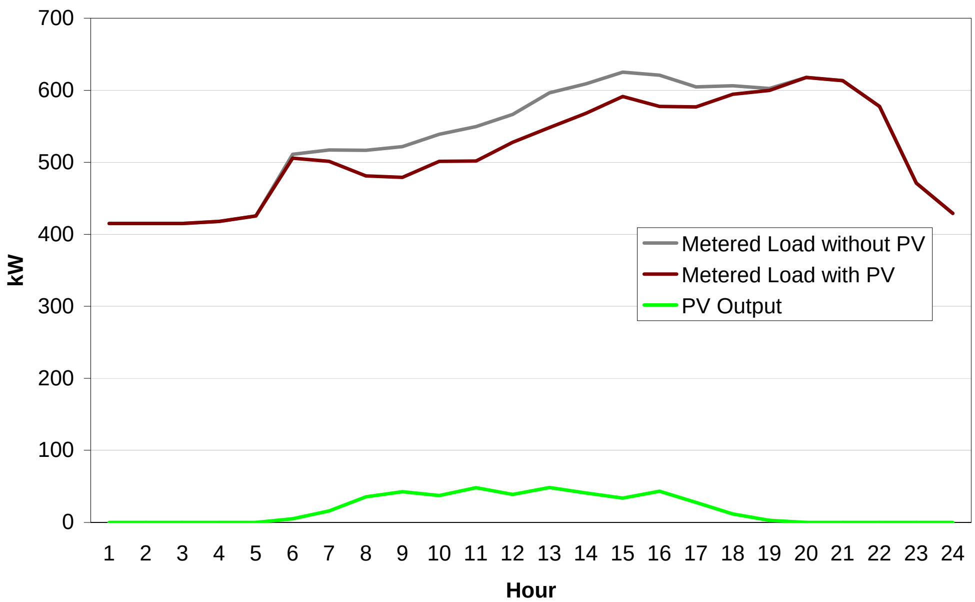


Figure 3: Peak Load Day for Large Grocery (as measured by meter) with PV - July

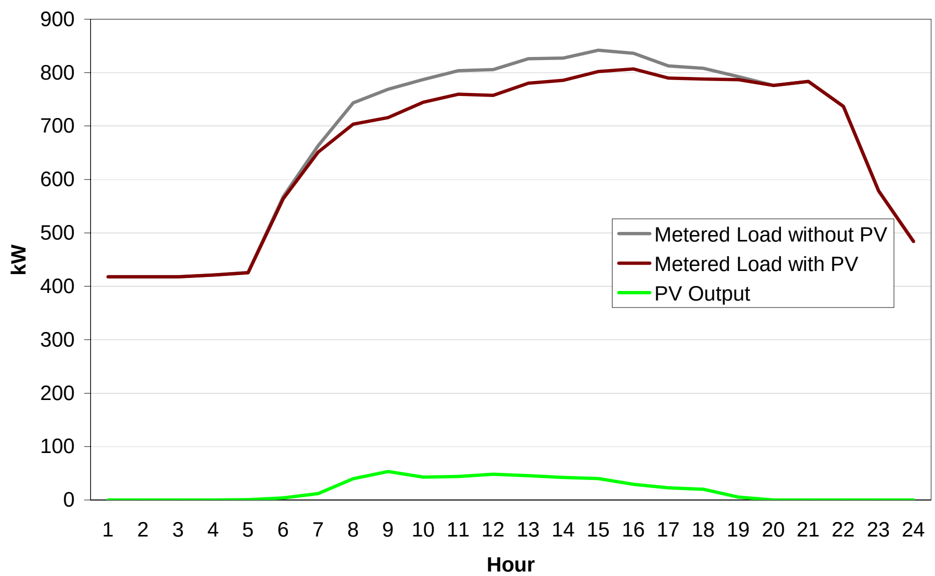
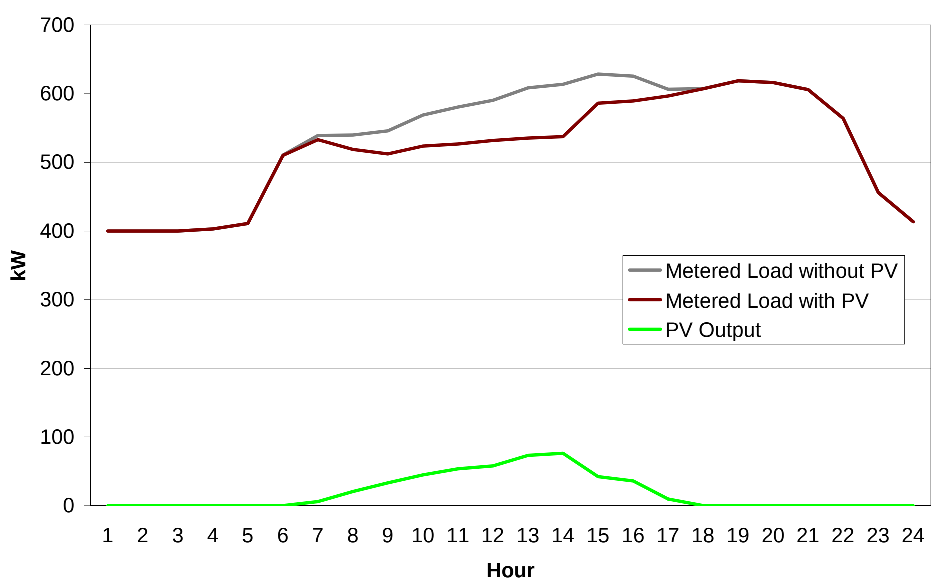


Figure 4: Peak Load Day for Large Grocery (as measured by meter) with PV - October



Next, the model required information about the type of DG equipment that would be used to produce onsite power. I selected two generation types to illustrate both intermittent and dispatchable generation technologies, with very different capacity factors as a result:

- A 200 kWp dc (177.8 kWac) PV array, flat roof-mounted, with an annual capacity factor of 16.41% (measured against the AC rating), which is typical of such systems in the Boston area. Cost and operating data were obtained from industry reference documents, and discussions with regional PV generators. The system produces 255,547 kWh per year. The PV generation profile was developed using insolation data for the Boston area.
- A 200 kWp dc (177 kW ac) gas-fired GenSet, operating at 100% capacity factor. The system produces 1,557,512 kWh per year.

Table 1 below shows bill impacts I have prepared for illustrative DG customers in terms of a particular end-use customer type (a large grocery store or a large office building) along with the type of DG used (a 200kW PV array or a 200kW baseload GenSet), and the applicable NSTAR Rate Class. The table shows the change in annual bill savings (and the percentage change in savings) attributable to the proposed standby rates, relative to the existing rates.

Table 1: Summary of Change in $ Bill Savings and % Change in Bill Savings Comparing Proposed Standby Rate to Existing Tariffs

		Boston Edison	Commonwealth Electric	Cambridge Electric	
	Current Rate	**T-2**	**G-3**	**G-2**	**G-3**
	vs. Standby Rate	**SB-1**	**SB-1**	**SB-2**	**SB-3**
Large Grocery W/ PV	$ Δ Bill Savings	$-3,737	$7,980	$5,483	$1,308
	% Change in Savings	-15.9%	33%	25.6%	6.8%
Large Office W/ PV	$ Δ Bill Savings	$-7,287	$-77	$-4,291	$950
	% Change in Savings	-25.6%	0%	-18.0%	4.5%
Large Grocery W/ GenSet	$ Δ Bill Savings	$-24,089	$-386	$-5,291	$-1,800
	% Change in Savings	-17.7%	-1.0%	-3.9%	-1.5%
Large Office W/ GenSet	$ Δ Bill Savings	$-24,089	$-9,228	$-14,562	$-1,800
	% Change in Savings	-17.7%	-6.2%	-11%	-1.5%

Note: A negative "Δ Bill Savings" indicates reduced bill savings from DG operation due to standby rate

The Boston Edison SB-1 rate shows the most consistent and worrisome pattern: the standby rate <u>reduces</u> bill savings resulting from DG operation under the current tariff by 16% to 26%. Conversely, the same large grocery store (using PV) would see a significant annual <u>increase</u> in bill savings under the standby rates applicable to the Commonwealth G-3 tariff and the Cambridge Electric G-2 tariff. A significant portion of the benefit shown is due to the rate redesign, and this is only partially offset by imposition of the standby charge. Lower load factors of the end-user (such as the office building) and higher capacity factors of the DG resource (such as the GenSet) also contribute to the reduction in bill savings stemming from the application of the proposed standby rates.

At the project level, the standby rate would also have a measurable effect on financials results and overall investment viability. For example, based on realistic investment parameters for the 200kW PV installation at a large grocery store, the BECo standby rate would reduce the project's internal rate of return (IRR) from 12% to 10%; for the large office building the IRR for the PV system would fall from 14% to 11% due to the standby rate. These figures assume the continuation of various support and incentive mechanisms currently in place.[4] These results demonstrate the somewhat precarious investment context facing PV, and the very real potential for the proposed standby rates to terminate otherwise viable projects from moving forward.

Additional information about the rate impacts of the standby rates is contained in Tables 2 through 5. These tables show at a more focused level how the various standby rates interact with different end users, DG profiles, and other iterative changes. For example, in Table 2, the entire table evaluates the case of the large grocery store with the PV system described earlier. The first row shows the annual bill assuming the current general service rate, with no PV present at the building. This is the reference point against which all other comparisons on the table are made, and there are accordingly no savings shown. The next row shows

[4] For example, the Massachusetts Technology Collaborative PV buydown program is assumed to cut the installed cost of PV in half, or by \$3.35 per $Watt_p$. Federal tax credits, renewable energy credits (RECs) and accelerated depreciation are also included in the analysis.

the customer’s bill under the standby rate, but without the benefit of the PV system. This row isolates the rate re-design effect of the standby charge. We can see that there are substantial savings for the Commonwealth G-3 and Cambridge G-2 customers, purely as a result of the migration of costs from the energy charge to the demand charge component of the rate. The third row shows the annual bill with the PV in operation, under the current general service (or TOU) tariff. The PV generation produces rate savings due to avoided energy costs and avoided demand charges, since the existing tariffs do not use a standby mechanism. Finally, the fourth row shows the annual bills under the proposed standby rates.

For Boston Edison, the savings decrease due to the effect of the standby mechanism, which takes back demand charge savings when the PV output occurs in metered peak demand hours. For the Commonwealth and Cambridge cases, the bill savings exceed the current case (Row 3) because the rate-redesign benefits are still much greater than the punitive effects of the standby charge. Row 4 is roughly equivalent to the savings in Row 2 (Rate redesign) plus the savings in Row 3 – less the amount of reduced savings stemming from the standby charge.

Table 2: Large Grocery – PV Analysis

Building characteristics: 100,000 sqft, peak load = 855kW, annual consumption = 4,773,660kWh, annual capacity factor = 63.7%

PV Characteristics: Nominal 200kW rating, peak output = 177.8 kW, annual production = 255, 547 kWh, annual capacity factor = 16.4%

		Boston Edison	Commonwealth Electric	Cambridge Electric	
	Current Rate	**T-2**	**G-3**	**G-2**	**G-3**
	Standby Rate	**SB-1**	**SB-1**	**SB-2**	**SB-3**
Current Rate, no PV	Annual Electricity Bill	$455,640.11	$472,141.19	$429,088.67	$381,369.23
	Savings (Loss)	N/A	N/A	N/A	N/A
Standby Rate, no PV	Annual Electricity Bill	$455,640.11	$462,095.88	$421,707.03	$379,605.23
	Savings (Loss)	$0.00	$10,045.32	$7,381.64	$1,764.00
Current Rate, with PV	Annual Electricity Bill	$432,202.39	$447,991.23	$407,671.07	$362,219.58
	Savings (Loss)	$23,437.72	$24,149.96	$21,417.60	$19,149.66
Standby Rate, with PV	Annual Electricity Bill	$435,939.38	$440,011.96	$402,187.93	$360,911.32
	Savings (Loss)	$19,700.73	$32,129.24	$26,900.74	$20,457.92

Note: All Savings are relative to the "Current Rate, no PV" case and exclude taxes.

Table 3: Large Office – PV Analysis

Building characteristics: 317,922 sqft, peak load = 1,473kW, annual consumption = 4,773,660kWh, annual capacity factor = 37.0%

PV Characteristics: Nominal 200kW rating, peak output = 177.8 kW, annual production = 255, 547 kWh, annual capacity factor = 16.4%

		Boston Edison	Commonwealth Electric	Cambridge Electric	
	Current Rate	**T-2**	**G-3**	**G-2**	**G-3**
	Standby Rate	**SB-1**	**SB-1**	**SB-2**	**SB-3**
Current Rate, no PV	Annual Electricity Bill	$551,169.51	$503,581.62	$477,083.26	$415,558.31
	Savings (Loss)	N/A	N/A	N/A	N/A
Standby Rate, no PV	Annual Electricity Bill	$551,169.51	$501,377.57	$478,972.40	$413,794.31
	Savings (Loss)	$0.00	$2,204.05	$(1,889.14)	$1,764.00
Current Rate, with PV	Annual Electricity Bill	$522,721.72	$478,111,12	$453,310.17	$394,707.32
	Savings (Loss)	$28,447.79	$25,470.51	$23,773,10	$20,850.98
Standby Rate, with PV	Annual Electricity Bill	$530,008.62	$478,187.91	$457,600.64	$393,757.88
	Savings (Loss)	$21,160.89	$25,393.71	$19,482.62	$21,800.43

Note: All Savings are relative to the "Current Rate, no PV" case and exclude taxes.

Table 4: Large Grocery – Baseload GenSet Analysis

Building characteristics: 100,000 sqft, peak load = 855kW, annual consumption = 4,773,660kWh, annual capacity factor = 63.7%

GenSet Characteristics: Nominal 200kW rating, peak output = 177.8 kW, annual production = 1,557,512 kWh, annual capacity factor = 100%

		Boston Edison	Commonwealth Electric	Cambridge Electric	
	Current Rate	**T-2**	**G-3**	**G-2**	**G-3**
	Standby Rate	**SB-1**	**SB-1**	**SB-2**	**SB-3**
Current Rate, no GenSet	Annual Electricity Bill	$455,640.11	$472,141.19	$429,088.67	$381,369.23
	Savings (Loss)	N/A	N/A	N/A	N/A
Standby Rate, no GenSet	Annual Electricity Bill	$455,640.11	$462,095.88	$421,707.03	$379,605.23
	Savings (Loss)	$0.00	$10,045.32	$7,381.64	$1,764.00
Current Rate, with GenSet	Annual Electricity Bill	$319,534.03	$325,288.33	$293,920.27	$260,926.93
	Savings (Loss)	$136,106.07	$146,852.86	$135,168.40	$120,442.30
Standby Rate, with GenSet	Annual Electricity Bill	$343,622.13	$326,674.96	$299,211.67	$262,726.98
	Savings (Loss)	$112,017.98	$145,466.24	$129,877.00	$118,642.26

Note: All Savings are relative to the “Current Rate, no GenSet” case and exclude taxes.

Table 5: Large Office – Baseload GenSet Analysis

Building characteristics: 317,922 sqft, peak load = 1,473kW, annual consumption = 4,773,660kWh, annual capacity factor = 37.0%

GenSet Characteristics: Nominal 200kW rating, peak output = 177.8 kW, annual production = 1,557,512 kWh, annual capacity factor = 100%

		Boston Edison	Commonwealth Electric	Cambridge Electric	
	Current Rate	**T-2**	**G-3**	**G-2**	**G-3**
	Standby Rate	**SB-1**	**SB-1**	**SB-2**	**SB-3**
Current Rate, no GenSet	Annual Electricity Bill	$551,169.51	$503,581.62	$477,083.26	$415,558.31
	Savings (Loss)	N/A	N/A	N/A	N/A
Standby Rate, no GenSet	Annual Electricity Bill	$551,169.51	$501,377.57	$478,972.40	$413,794.31
	Savings (Loss)	$0.00	$2,204.05	$(1,889.14)	$1,764.00
Current Rate, with GenSet	Annual Electricity Bill	$415,063.44	$356,728.76	$341,914.86	$295,116.01
	Savings (Loss)	$136,106.07	$146,852.86	$135,168.40	$120,442.30
Standby Rate, with GenSet	Annual Electricity Bill	$439,151.54	$365,956.65	$356,477.05	$296,916.05
	Savings (Loss)	$112,017.98	$137,624.97	$120,606.22	$118,642.26

Note: All Savings are relative to the “Current Rate, no GenSet” case and exclude taxes.

Similar analyses are done on the Tables 3-5 for the Large Office/PV, the Large Grocery/GenSet, and Large Office/GenSet cases. The analytical process is similar in each of these examples.

Q. Please describe the current market in Massachusetts for behind-the-meter PV systems that exceed the net-metering threshold of 60kW.

A. According to the most recent reports issued by the investor-owned electric distribution companies in Massachusetts for calendar 2002, there are currently no behind-the-meter PV systems that exceed 60 kW of PV capacity alone. However, the Williams Building in downtown Boston (used by the U.S. Coast Guard, operated by the General Services Administration) has a 28kW PV array and a 75 kW gas cogeneration system, which means the PV system is non-net-metered, although it is less than 60kW by itself. Navigant Consulting, Inc. is aware of some facility developers who have expressed interest in installing large PV facilities that could exceed the 60kW threshold. There are hundreds of onsite PV installations in Massachusetts that are below the 60 kW threshold.

Q. Why is there more market activity for net-metered PV than non-net-metered PV systems in Massachusetts?

A. Although there are no behind-the-meter PV installations over 60 kW in Massachusetts at present, there have been a number of recent high-profile, large-scale PV projects taking place in other states such as New York, California, and New Jersey of several hundred kilowatts to as large as 1 MW. Many of the key factors driving the development of large scale PV installations in these states are also present in Massachusetts including: renewable portfolio standards, state buy-down funds targeted to PV projects, state tax credits and tax exemptions, retail choice/green power markets, emission allowance set-aside programs, and electricity labeling. Key distinctions between Massachusetts and these other states concerns the upper bound of net metering[5] and the direct involvement of municipal utilities and investor-owned utilities, which remain involved in generation planning and resource procurement.

Here in Massachusetts, there are also significant benefits associated with net metering that are not generally available to larger scale projects, which is also an important consideration in developer practices. Non net-metered systems do not have explicit protection in DTE regulations from backup and demand charges, such as those under consideration in this proceeding. In addition, non-net metered systems do not have the unilateral option to choose to run their meter backwards and export excess energy to the grid, and receive monetary credit for doing so. If lacking two-way flow capability, on-site generators will tend to size their systems around minimum load conditions, so as not to exceed disconnection relays that may be required under the interconnection protocol with the distribution utility.

In addition, interconnection issues tend to be more complex and costly for larger systems. With the recent issuance of <u>Investigation by the Department of Telecommunications and Energy on its own motion into Distributed Generation,</u> D.T.E. 02-38-B, (2004), there is a new and streamlined process for the interconnection of DG resources. These interconnection standards will be particularly beneficial to smaller DG resources that gain "simplified

[5] New Jersey is currently considering a draft regulation expanding the level for net-metered renewable DG installations to 2MW. California currently has a 1 MW threshold for net-metering.

interconnection" or "expedited interconnection" procedures. Although larger systems are likely to require a standard interconnection process, the standards have been clarified and are much more workable than before. In addition, interconnection provisions pursuant to the QF rules under 220 C.M.R. §§ 8.00 remain in effect, and constitute another useful pathway for non-net-metered systems to get interconnections.

The Department should recognize that project vulnerability to standby charges is a particular concern of the DG community and is often cited as one of the key impediments to more robust development of larger-size installations. This is an important policy issue because larger-scale DG projects, including PV, are critical to driving down the cost of installed systems and introducing cutting edge technologies and practices that ripple through the entire industry.

Q. What other policy considerations ought to have bearing on the Department's consideration of the NSTAR's standby rate proposal?

A. Many DG technologies offer much more than just kilowatts of capacity located at the customer's premises. Several renewable energy technologies, including PV, small wind, and potentially small biomass (in appropriate settings such as farms and wastewater treatment facilities) are ideally suited to onsite generation opportunities. These technologies run the gamut of capacities, and can be sized within net-metering limits, or at larger levels of capacity – where they could be subject to NSTAR's standby tariffs. Other forms of ultra clean DG production such as fuel cells also have desirable qualities and low or zero emission levels.

As noted earlier, the imposition of a standby charge appears to have an adverse impact on several DG configurations, and could frustrate efforts to get projects designed, built, and into operation. If DG projects such as large-scale PV installations are the casualty of the standby rates, a number of benefits, direct and indirect will be lost to generators, other ratepayers, and society in general. For example, the successful development of PV facilities will introduce a greater supply of renewable energy certificates (RECs) to the marketplace, which will help to moderate compliance costs by retail suppliers who must meet the RPS. Reduced compliance costs for RPS (which is supported by all ratepayers) provide a general benefit for all ratepayers. Similarly, all citizens will benefit from cleaner power that PV and other ultra clean technologies such as fuel cells provide, made even more valuable by the delivery of power to exactly where it is needed (load centers), without environmental harm.

In addition, although photovoltaic electricity is an intermittent power source, it is closely correlated with system peaks, providing valuable energy and capacity when it is often most critical to the needs of the grid. Under existing rate structures, much of the peak-related benefit flows to the utility grid and is not captured by the PV generator in a financial sense. The standby rate (absent the rate-redesign element) would exacerbate this condition by taking back some of the already-muted demand charge savings afforded by PV available under currently tariffs.

Q. If a standby rate is adopted in the proceeding, do you have any recommendations as to how it can strike a proper balance between the various policy concerns?

A. If a standby rate is adopted in this proceeding, there are several steps the Department can take to ensure that the rate strikes reasonable balance competing policy objectives. The rate should be designed to provide safeguards against DG-related revenue erosion, if that occurs, only when there is a severe adverse impact consistent with existing legislative parameters for collection of "exit fees" in Ch. 164, §1G(g). If we reach that level of impact, exemptions to potentially punitive standby charges should be available if the results of standby rates conflict with clear policy mandates (such as the RPS) or practical rate administration matters. Before standby rates are imposed on any customers, the following questions should be posed. A standby charge should be imposed only if the DG customer is ineligible for any of the following exemptions. If an onsite DG generation customer wishes to take service under a standby tariff (even if an exemption is applicable) the customer should have the option to do so.

Test 1: Has the distribution utility experienced a loss of at least 10% of its gross revenues relating to the installation and use of on-site generation? If not, all on-site generators are exempt from the standby rates consistent with the test delineated in Ch. 164, §1G(g) of the imposition of exit fees.

Test 2: Is the standby generator larger than 60 kW? If so, the first 60 kW would be automatically exempt from any standby rate, similar to the exiting exemption afforded net-metering customers who are 60 kW or less, under 220 CMR 11.04(7)(c).

Test 3: Is the DG generator an MTC eligible resource?[6] If so, the customer is exempt.

Test 4: Is the DG generator a non-emitting resource? If so, the customer is exempt.

Test 5: Is the average output of the DG system during 15 – minute demand-interval peaks less than 20% of the metered demand levels used for billing purposes? If so, the customer is exempt

Q. Does this conclude your testimony?

A. Yes

[6] MTC eligible resources include: solar photovoltaic and solar thermal electric energy; wind energy; ocean thermal, wave, or tidal energy; fuel cells (including natural gas-fired); landfill gas; naturally flowing water and hydroelectric; low emission, advanced biomass; and storage and conversion technologies connected to qualifying generation projects. M.G.L. c. 40J, §4E(f).

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Professional History

- Principal, Navigant Consulting, Inc. (1999 - Present)
- President, Greene Energy & Environmental Company (1995 - 1999)
- Assistant Secretary, Policy and Planning Massachusetts Executive Office of Environmental Affairs (1991 - 1995)
- Director, Gas & Water Division, Massachusetts Department of Public Utilities (1985 - 1989)
- Regional Credit Manager, Data General Corporation (1983 - 1985)

Education

- M.B.A., Finance, Boston College Graduate School of Management, 1991
- B.A., Economics (magna cum laude), Tufts University, 1983

Andrew Greene, a Principal with Navigant Consulting, has an extensive background in regulatory policy development, environmental compliance requirements, finance, state utility regulation, strategic planning, project development, energy marketing, corporate environmental improvement programs, and energy and environmental communications.

Professional Experience

Environmental Analysis and Project Management

» Conducted a comprehensive environmental risk review for a major U.S. electric utility including its regulated and unregulated business units. Reviewed the company's Integrated Resource Plan and suggested modifications and improvements for successive filings, and new approaches for gaining favorable regulatory review in a multi-state context.

» Managed environmental aspects of numerous generation asset divestitures of large electric utilities. Prepared environmental sections of offering documents; reviewed and quantified existing and prospective regulatory risks; advised on scope and preparation of environmental site assessments; analyzed potential remediation measures and quantified potential liabilities; explored use of environmental insurance products to facilitate transactions; responded to bidder inquiries, and conducted site tours with bidders and plant personnel.

» Assisted a major gas utility with financial and technical assessment of manufactured gas plant sites in a successful insurance recovery process. Developed a cost-recovery mechanism for utility and prepared testimony for rate case before public utility commission.

» Appeared as environmental and economics expert witness for a northeastern nuclear generating facility seeking a certificate of public good for expansion of an existing facility.

- Developed environmental strategic plans for merchant and utility generation companies. Projects included review of existing and future regulations, analysis of control technology options, emissions market forecasting, and probabilistic modeling of financial results. Briefed senior management on recommended strategies and facilitated plan adoption.
- Authored sections of recently completed multi-client study of the renewables industry on tradable certificates, emissions, and portfolio standards.
- Presented whitepaper to the National Association of Regulatory Utility Commissioners (NARUC) on the design and implementation of Renewable Portfolio Standards and policy coordination with information disclosure, "green marketing," generation performance standards and other state and federal policies.
- Assisted a prominent, environmentally oriented, national retail electricity supplier with its compliance strategies and policy development relating to information disclosure requirements, renewable portfolio standards, and generation performance standards.
- Analyzed environmental implications of changes in rate design policy for interruptible gas transportation in Massachusetts.
- Developed information label now used in Massachusetts to inform retail consumers about the price, fuel mix and environmental characteristics of competitive power supplies.
- Wrote and produced a manual for industrial companies evaluating and implementing energy efficiency and pollution prevention options for U.S. EPA/DOE ClimateWise project.
- Researched, wrote, and produced "The Massachusetts Electric Vehicle Demonstration Program: First Year Program Results" and "Electric Vehicle Charging Equipment Installation Guide" for the Massachusetts Division of Energy Resources.
- Organized a major conference and wrote the companion report on the implications of electric utility restructuring for New England businesses and the environment.
- Assisted a major gas utility in analyzing its demand-side management programs and current rate structures and developing more market-responsive alternatives.

Environmental Studies

- Advised several industrial end-users on strategies for reducing electricity and gas costs and improving environmental quality through the purchase of unbundled utility services.
- Advised Massachusetts and other Northeastern states on a region-wide NOx control strategy and allowance trading program leading to the Ozone Transport Commission's Memorandum of Understanding.
- Directed the planning and implementation of major policy initiatives for land use management, pollution prevention, and resource conservation. Oversaw the work of Massachusetts Executive Office of Environmental Affairs (EOEA) staff and agencies to ensure policies and programs were coordinated and effective. Presented briefings and speeches on key environmental issues before senior government officials, industry, and environmental groups. Prepared testimony for the Governor and Lt. Governor in their congressional and legislative appearances on pending environmental matters such as reauthorization of the Clean Water Act, and implementation of the Clean Air Act Amendments.

- Spearheaded implementation of Governor's "Clean State" Executive Order. Wrote environmental handbook for state employees and supervised pollution prevention plans throughout state government.
- Led effort to design and implement Massachusetts' nationally recognized emissions trading program.
- Directed legislative and regulatory initiatives regarding environmentally sound packaging and siting reform for energy and hazardous waste facilities.
- Organized and chaired Northeastern Governors/Eastern Canadian Premiers conference on climate change.
- Directed EOEA involvement in state plans for energy, economic development, and transportation.
- Organized business partnerships to use innovative environmental technology in state facilities.

Gas and Water Regulation

- Oversaw all administrative, procedural, and substantive aspects involved in the regulation of gas and water utilities for the Massachusetts Department of Public Utilities (MDPU). Supervised completion of general rate cases and other rate design proceedings.
- Enhanced the role of natural gas as a key component in the Commonwealth's energy mix through collaborative development of energy efficiency programs with major utilities, introduction of direct-access gas transportation services in Massachusetts, and the promotion of new market opportunities.
- Helped design an efficient settlement process for resolution of small water utility cases, cutting time and expense of the traditional adjudicatory process.
- Assisted in coordinating and managing all aspects of Gas & Water Division staff casework, developing strategic plans, and implementing personnel policy. Provided guidance to staff on all aspects of case work, including identification of issues, application of MDPU case precedent, preparation of data requests and cross examination, and preparation of MDPU decisions.
- Examined case filings, cross-examined expert witnesses, and prepared draft decisions in proceedings before the MDPU. Recommended allowable revenue requirements and appropriate utility rates to the Commission based on review of cost studies and customer impact analyses. Developed rate designs that afforded access to service by low-income customers, without undue impact on other customer classes. Researched and developed policy initiatives for Commission consideration in response to changes in the energy market and federal regulations.

Finance

- Developed and administered credit policies for the Data General Dealer Program. Analyzed financial statements, bank and trade references, and industry reports to select financially qualified applicants and establish customer credit lines. Oversaw a portfolio of more than 200 accounts.